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Chapter 4: Geological Carbon Sequestration

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Chapter 4: Geological Carbon Sequestration

Carbon sequestration is the long term isolation of carbon dioxide from the atmosphere through physical, chemical, biological, or engineered processes. The largest potential reservoirs for storing carbon are the deep oceans and geological reservoirs in the earth's upper crust. This chapter focuses on geological sequestration because it appears to be the most promising large-scale approach for the 2050 timeframe. It does not discuss ocean or terrestrial sequestration¹.

In order to achieve substantial GHG reductions, geological storage needs to be deployed at a large scale.^{1,2} For example, 1 Gt C/yr (3.6 Gt CO₂/yr) abatement, requires carbon capture and storage (CCS) from 600 large pulverized coal plants (~1000 MW each) or 3600 injection projects at the scale of Statoil's Sleipner project.² At present, global carbon emissions from coal approximate 2.5 Gt C. However, given reasonable economic and demand growth projections in a business-as-usual context, global coal emissions could account for 9 Gt C (see table 2.7). These volumes highlight the need to develop rapidly an understanding of typical crustal response to such large projects, and the magnitude of the effort prompts certain concerns regarding implementation, efficiency, and risk of the enterprise.

The key questions of subsurface engineering and surface safety associated with carbon sequestration are:

Subsurface issues:

¹ From a technical perspective, ocean sequestration appears to be promising due to the ocean's capacity for storage (IPCC 2005). Presently, because of concerns about environmental impacts, ocean sequestration has become politically unacceptable in the US and Europe. Terrestrial storage, including storage in soils and terrestrial biomass, remains attractive on the basis of ease of action and ancillary environmental benefits. However, substantial uncertainties remain regarding total capacity, accounting methodology, unforeseen feedbacks and forcing functions, and permanence.

² A 1000 MW bituminous pulverized coal plant with 85% capacity factor and 90% efficient capture would produce a CO₂ stream mass of 6.24 million t/yr. If injected at 2 km depth with a standard geothermal gradient, the volume rate of supercritical CO₂ would be 100,000 barrels/day (for comparison, the greatest injection rate for any well in the world is 40,000 bbl/d, and typical rates in the US are <3000 bbl/d). This suggests that initially either multiple long-reach horizontal wells or tens of vertical wells would be required to handle the initial volume. Over 50 years, the lifetime typical of a large coal plant, this would be close to 2 billion barrels equivalent, or a giant field for each 1000 MW plant.

- Is there enough capacity to store CO₂ where needed?
- Do we understand storage mechanisms well enough?
- Could we establish a process to certify injection sites with our current level of understanding?
- Once injected, can we monitor and verify the movement of subsurface CO₂?

Near surface issues:

- How might the siting of new coal plants be influenced by the distribution of storage sites?
- What is the probability of CO₂ escaping from injection sites? What are the attendant risks? Can we detect leakage if it occurs?
- Will surface leakage negate or reduce the benefits of CCS?

Importantly, there do not appear to be unresolvable open technical issues underlying these questions. Of equal importance, the hurdles to answering these technical questions well appear manageable and surmountable. As such, it appears that geological carbon sequestration is likely to be safe, effective, and competitive with many other options on an economic basis. This chapter explains the technical basis for these statements, and makes recommendations about ways of achieving early resolution of these broad concerns.

Scientific Basis

A number of geological reservoirs appear to have the potential to store many 100's – 1000's of gigatons of CO₂.³ The most promising reservoirs are *porous and permeable rock bodies*, generally at depths, roughly 1 km, at pressures and temperatures where CO₂ would be in a supercritical phase.⁴

- *Saline formations* contain brine in their pore volumes, commonly of salinities greater than 10,000 ppm.
- *Depleted oil and gas fields* have some combination of water and hydrocarbons in their pore volumes. In some cases, economic gains can be achieved through enhanced oil recovery (EOR)⁵ or enhanced gas

recovery⁶ and substantial CO₂-EOR already occurs in the US with both natural and anthropogenic CO₂.⁷

- *Deep coal seams*, often called unmineable coal seams, are composed of organic minerals with brines and gases in their pore and fracture volumes.
- Other potential geological target classes have been proposed and discussed (e.g., oil shales, flood basalts); however, these classes require substantial scientific inquiry and verification, and the storage mechanisms are less well tested and understood (see Appendix 4.1 for a more detailed explanation).

Because of their large storage potential and broad distribution, it is likely that most geological sequestration will occur in saline formations. However, initial projects probably will occur in depleted oil and gas fields, accompanying EOR, due to the density and quality of subsurface data and the potential for economic return (e.g., Weyburn). Although there remains some economic potential for enhanced coal bed methane recovery, initial economic assessments do not appear promising, and substantial technical hurdles remain to obtaining those benefits.³

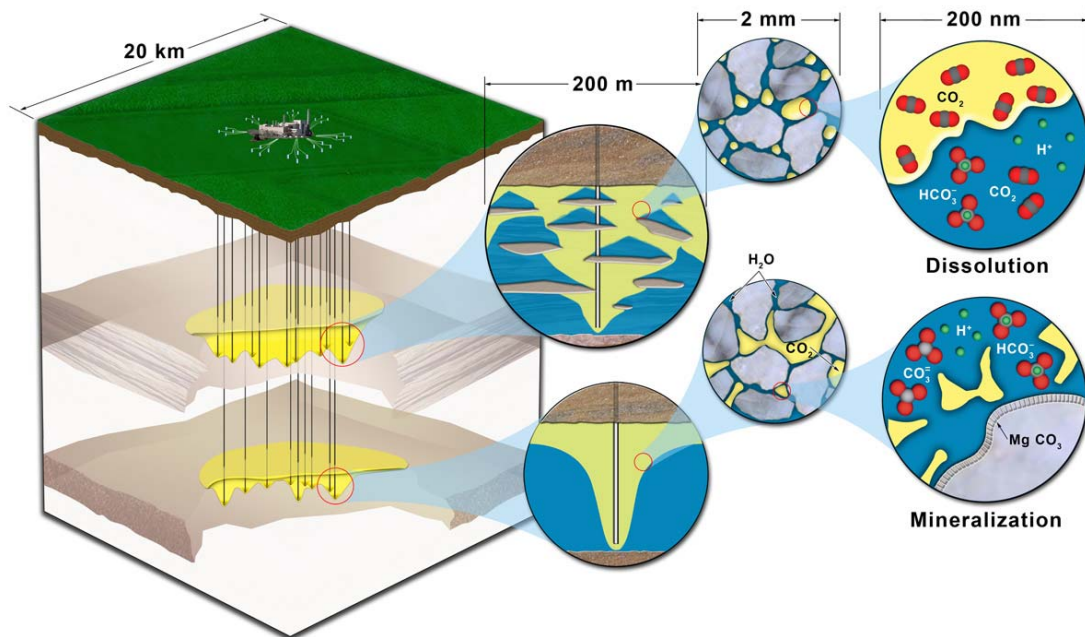


Figure 4.1: Schematic diagram of large injection at 10 years time illustrating the main storage mechanisms. All CO₂ plumes (yellow) are trapped beneath impermeable shales (not shown). The upper unit is heterogeneous with a low net percent usable, the lower unit is homogeneous. Central insets show CO₂ as a mobile phase (lower) and as a trapped residual phase (upper). Right insets show CO₂ dissolution (upper) and CO₂ mineralization (lower).

For the main reservoir classes, CO₂ storage mechanisms are reasonably well defined and understood (Figure 4.1). To begin, CO₂ sequestration targets will have *physical barriers* to CO₂ migration out of the crust to the surface. These barriers will commonly take the form of impermeable layers (e.g., shales, evaporites) overlying the reservoir target, although they may also be dynamic in the form of regional hydrodynamic flow. This storage mechanism allows for very high CO₂ pore volumes, in excess of 80%, and act immediately to limit CO₂ flow. At the pore scale, *capillary forces* will immobilize a substantial fraction of a CO₂ bubble, commonly measured to be between 5 and 25% of the pore volume. That CO₂ will be trapped as a residual phase in the pores, and acts over longer time scales as a CO₂ plume which is attenuated by flow. Once in the pore, over a period of tens to hundreds of years, the CO₂ will *dissolve* into other pore fluids, including hydrocarbon species (oil and gas) or brines, where the CO₂ is fixed indefinitely, unless other processes intervene. Over longer time scales (hundreds to thousands of years) the dissolved CO₂ may react with minerals in the rock volume to *precipitate* the CO₂ as new carbonate minerals. Finally, in the case of organic mineral frameworks such as coals, the CO₂ will physically *adsorb* onto the rock surface, sometimes displacing other gases (e.g., methane, nitrogen).

Although substantial work remains to characterize and quantify these mechanisms, they are understood well enough today to trust in estimates of the percentage of CO₂ stored over some period of time as a result of decades of studies in analogous hydrocarbon systems, natural gas storage operations, and CO₂-EOR. Specifically, it is very likely that the fraction of stored CO₂ will be greater than 99% over 100 years, and likely that the fraction of stored CO₂ will exceed 99% for 1000 years³. Moreover, some mechanisms appear to be self-reinforcing.^{8,9} Additional work will reduce the uncertainties associated with long-term efficacy and numerical estimates of storage volume capacity, but no knowledge gaps today appear to cast doubt on the fundamental likelihood in the feasibility of CCS.

Capacity estimates

While improvement in understanding of storage mechanisms would help to improve capacity estimates, the fundamental limit to high quality storage estimates is

uncertainty in the pore volumes themselves. Most efforts to quantify capacity either regionally or globally are based on vastly simplifying assumptions about the overall rock volume in a sedimentary basin or set of basins.^{10,11} Such estimates, sometimes called “top-down” estimates, are inherently limited since they lack information about local injectivity, total pore volumes at a given depth, concentration of resource (e.g., stacked injection zones), risk elements, or economic characteristics.

A few notable exceptions to those kinds of estimates involve systematic consideration of individual formations and their pore structure within a single basin.¹² The most comprehensive of this kind of analysis, sometimes called “bottom-up”, was the GEODISC effort in Australia.¹³ This produced total rock volume estimates, risked volume estimates, pore-volume calculations linked to formations and basins, injectivity analyses, and economic qualifications on the likely injected volumes. This effort took over three years and \$10 million Aus. Institutions like the US Geological Survey or Geoscience Australia are well equipped to compile and integrate the data necessary for such a capacity determination, and would be able to execute such a task rapidly and well.

Our conclusions are similar to those drawn by the Carbon Sequestration Leadership Forum (CSLF), which established a task force to examine capacity issues.¹⁴ They recognized nearly two-orders of magnitude in uncertainty within individual estimates and more than two orders magnitude variance between estimates (Figure 4.2). The majority of estimates support the contention that sufficient capacity exists to store many 100’s to many 1000’s of gigatons CO₂, but this uncertain range is too large to inform sensible policy.

Accordingly, an early priority should be to undertake “bottom-up” capacity assessments for the US and other nations. Such an effort requires detailed information on individual rock formations, including unit thickness and extent, lithology, seal quality, net available percentage, depth to water table, porosity, and permeability. The geological character and context matters greatly and requires some expert opinion and adjudication. While the data handling issues are substantial, the costs would be likely to be low (\$10-50 million for a given continent; \$100 million for the world) and would be highly likely to provide direct benefits in terms of resource management.¹⁵ Perhaps more importantly,

they would reduce substantially the uncertainty around economic and policy decisions regarding the deployment of resource and crafting of regulation.

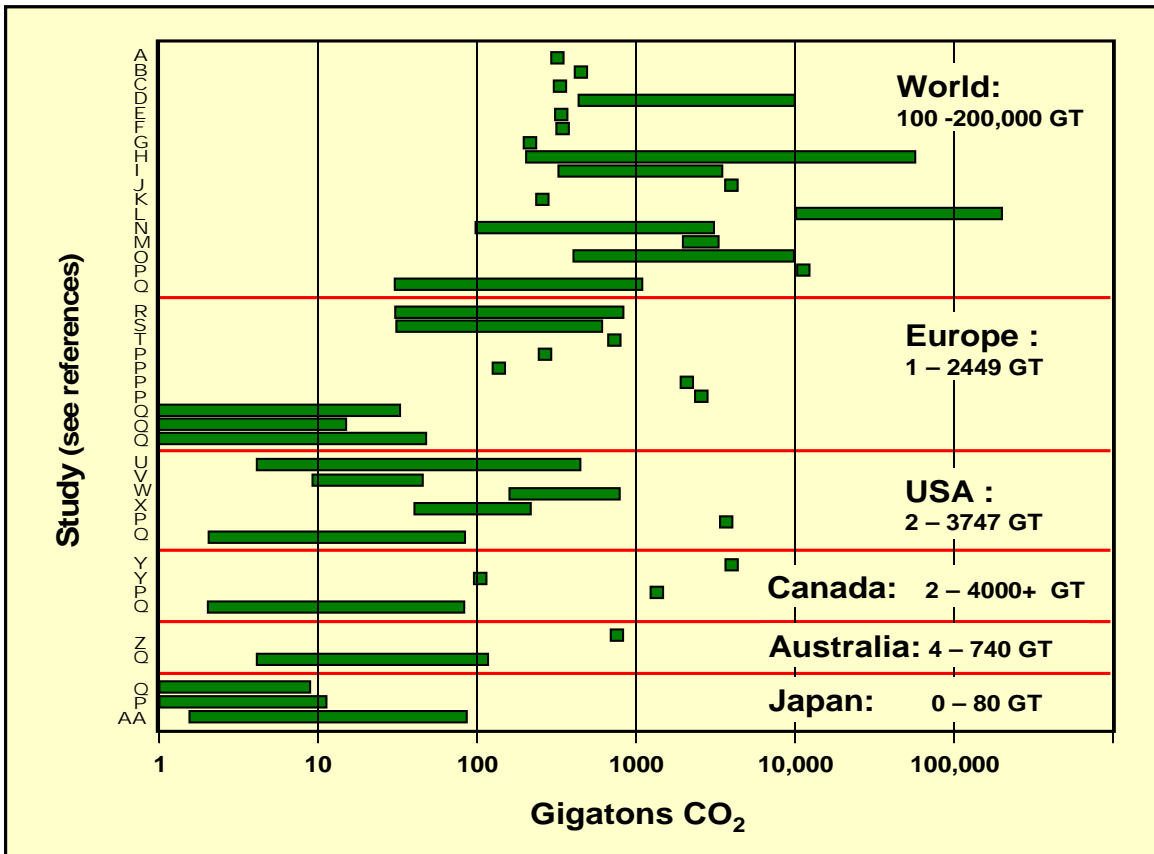


Figure 4.2: Graph showing published estimates of CO₂ capacity for the world, regions, and nations. Error! Bookmark not defined. Note the large potential range of in some estimates (greater than 100x) and the unreasonably small uncertainties in other estimates (none provided). Note that some national estimates exceed some global estimates.

Within the US, there is an important institutional hurdle to these kinds of capacity estimates. The best organization to undertake this effort would be the US Geological Survey, ideally in collaboration with industry, state geological surveys, and other organizations. This arrangement would be comparable in structure and scope to national oil and gas assessments, for which the USGS is currently tasked. This is analogous to performing a bottom-up CO₂ storage capacity estimation. However, the USGS has no mandate or resources to do CO₂ sequestration capacity assessments so at this time.

The Department of Energy has begun assessment work through the seven Regional Carbon Sequestration Partnerships¹⁶. These partnerships include the member organizations of 40 states, including some state geological surveys. While the

Partnerships have produced and will continue to produce some detailed formation characterizations, coverage is not uniform and the necessary geological information not always complete. As such, a high-level nationwide program dedicated to bottom-up geological assessment would best serve the full range of stakeholders interested in site selection and management of sequestration, as do national oil and gas assessments.

Site Selection and Certification Criteria

Capacity estimates, in particular formation-specific, local capacity assessments, will underlie screening and site selection and help define selection criteria. It is likely that for each class of storage reservoir, new data will be required to demonstrate the injectivity, capacity, and effectiveness (ICE) of a given site.³ A firm characterization of ICE is needed to address questions regarding project life cycle, ability to certify and later close a site, site leakage risks, and economic and liability concerns.¹⁷

Ideally, project site selection and certification for injection would involve detailed characterization given the geological variation in the shallow crust. In most cases, this will require new geological and geophysical data sets. The specifics will vary as a function of site, target class, and richness of local data. For example, a depleted oil field is likely to have well, core, production, and perhaps seismic data that could be used to characterize ICE rapidly. Still additional data (e.g., well-bore integrity analysis, capillary entry pressure data) may be required. In contrast, a saline formation project may have limited well data and lack core or seismic data altogether. Geological characterization of such a site may require new data to help constrain subsurface uncertainty. Finally, while injectivity may be readily tested for CO₂ storage in an unmineable coal seam, it may be extremely difficult to establish capacity and storage effectiveness based on local stratigraphy. Accordingly, the threshold for validation will vary from class to class and site to site, and the due diligence necessary to select a site and certify it could vary greatly.

³ *Injectivity* is the rate at which CO₂ injection may be sustained over fairly long intervals of time (months to years); *Capacity* is the total volume of potential CO₂ storage CO₂ at a site or in a formation; *Effectiveness* is the ability of the formation to store the injected CO₂ well beyond the lifetime of the project.

Open issues: The specific concerns for each class of storage are quite different. For depleted hydrocarbon fields, the issues involve incremental costs necessary to ensure well or field integrity. For saline formations, key issues will involve appropriate mapping of potential permeability fast-paths out of the reservoir, accurate rendering of subsurface heterogeneity and uncertainty, and appropriate geomechanical characterization. For unmineable coal seams, the issues are more substantial: demonstration of understanding of cleat structure and geochemical response, accurate rendering of sealing architecture and leakage risk, and understanding transmissivity between fracture and matrix pore networks. For these reasons, the regulatory framework will need to be tailored to classes of sites.

Measurement, Monitoring, and Verification: MMV

Once injection begins, a program for measurement, monitoring, and verification (MMV) of CO₂ distribution is required in order to:

- understand key features, effects, & processes needed for risk assessment
- manage the injection process
- delineate and identify leakage risk and surface escape
- provide early warnings of failure near the reservoir
- verify storage for accounting and crediting

For these reasons, MMV is a chief focus of many research efforts. The US Department of Energy has defined MMV technology development, testing, and deployment as a key element to their technology roadmap,¹⁶ and one new EU program (CO₂ ReMoVe) has allocated €20 million for monitoring and verification. The IEA has established an MMV working group aimed at technology transfer between large projects and new technology developments. Because research and demonstration projects are attempting to establish the scientific basis for geological sequestration, they will require more involved MMV systems than future commercial projects.

Today there are three well-established large-scale injection projects with an ambitious scientific program that includes MMV: Sleipner (Norway)¹⁸, Weyburn

(Canada)¹⁹, and In Salah (Algeria)^{3, 20}. Sleipner began injection of about 1Mt CO₂/yr into the Utsira Formation in 1996.¹⁸ This was accompanied by time-lapse reflection seismic volume interpretation (often called 4D-seismic) and the SACS scientific effort. Weyburn is an enhanced oil recovery effort in South Saskatchewan that served as the basis for a four-year, \$24 million international research effort. Injection has continued since 2000 at about 0.85 Mt CO₂/yr into the Midale reservoir. A new research effort has been announced as the Weyburn Final Phase, with an anticipated budget comparable to the first. The In Salah project takes about 1Mt CO₂/yr stripped from the Kretchba natural gas field and injects it into the water leg of the field. None of these projects has detected CO₂ leakage of any kind, each appears to have ample injectivity and capacity for project success, operations have been transparent and the results largely open to the public.

Perhaps surprisingly in the context of these and other research efforts, there has been little discussion of what are the most important parameters to measure and in what context (research/pilot vs. commercial). Rather, the literature has focused on the current ensemble of tools and their costs.²¹ In part due to the success at Sleipner, 4-D seismic has emerged as the standard for comparison, with 4-D surveys deployed at Weyburn and likely to be deployed at In Salah. This technology excels at delineating the boundaries of a free-phase CO₂ plume, and can detect small saturations of conjoined free-phase bubbles that might be an indicator of leakage. Results from these 4D-seismic surveys are part of the grounds for belief in the long-term effectiveness of geological sequestration.

However, time-lapse seismic does not measure all the relevant parameters, and has limits in some geological settings. Key parameters for research and validation of CO₂ behavior and fate involve both direct detection of CO₂ and detection through proxy data sets (figure 4.3). Table 1 provides a set of key parameters, the current best apparent measurement and monitoring technology, other potential tools, and the status of deployment in the world's three largest injection demonstrations

Importantly, even in the fields where multiple monitoring techniques have been deployed (e.g., Weyburn), there has been little attempt to integrate the results (this was identified as a research gap from the Weyburn effort).^{Error! Bookmark not defined.} There are precious few formal methods to integrate and jointly invert multiple data streams. This is noteworthy; past analyses have demonstrated that formal integration of orthogonal data

often provides robust and strong interpretations of subsurface conditions and characteristics.^{22,23} The absence of integration of measurements represents a major gap in current MMV capabilities and understanding.

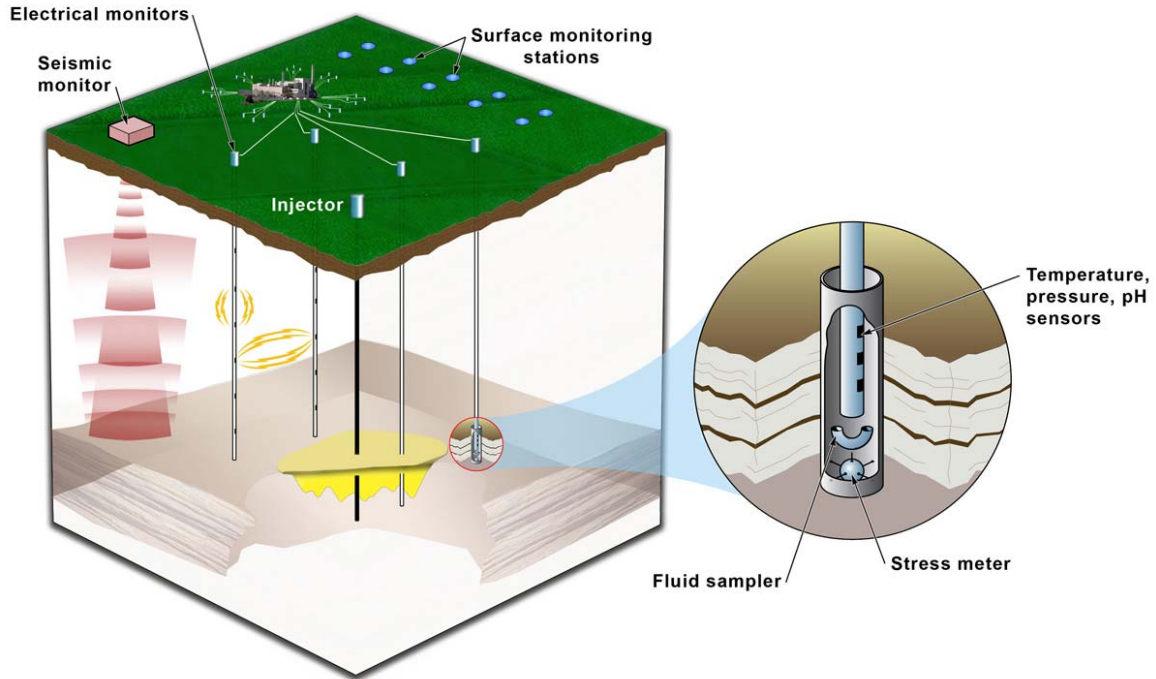


Figure 4.3: Schematic diagram a monitoring array providing insight into all key parameters. Note both surface and subsurface surveys, and down-hole sampling and tool deployment. A commercial monitoring array would probably be much larger.

Table 4.1: Key MMV parameters & environments, methods, and large-scale deployments

Parameter	Viable tools	Weyburn	In Salah, [†]	Sleipner
Fluid composition	Direct sample at depth [§] (e.g., U-tube), surface sampling	some	??	no
T, P fieldwide	Thermocouples [§] , pressure transducers [§] , fiberoptic Bragg grating	no	??	no
Subsurface pH monitoring	Down hole pH sensors [§]	no	yes [§]	no
CO ₂ distribution	Time-lapse seismic [§] , tilt, ERT, EMIT, microseismic	one [§]	one [§] or more	one [§]
CO ₂ saturation	ERT [§] , EMIT [§] , advanced seismic methods	no	no	no
Stress changes	Tri-axial tensiometers [§] , fiberoptic Bragg grating	no	??	no
Surface detection	Eddy towers [§] , soil gas, FTIRS, LIDAR, PFC tracing [§] , noble gas tracing	one	??	one*

ERT = Electrical Resistivity Tomography,

EMIT = Electromagnetic Induction Tomography

[§] Indicates best in class monitoring technology

[†] In Salah is still in the process of finalizing their monitoring array.

* The “surface” monitoring at Sleipner is different than other fields in that it is submarine rather than subaerial. Photo surveys and side-scan sonar surveys have not shown leakage

In addition to development, testing, and integration of MMV technology, there is no standard accepted approach (e.g., best practices) to the operation of MMV networks. This is particularly important in future commercial projects, where a very small MMV

suite focused on leak detection may suffice. To be effective, it is likely that MMV networks must cover the footprint of injection at a minimum, and include sampling near the reservoir and at the surface. Within the context of a large-scale deployment, it is likely that determination and execution of monitoring will involve a four-phase approach.

1. **Assessment and planning:** During this phase, the site is characterized geographically, geologically, geophysically, and geochemically. Forward simulation of monitoring approaches will help to predict the detection thresholds of a particular approach or tool. Based on this analysis, an array can be designed to meet the requirements of regulators and other stakeholders.
2. **Baseline monitoring:** Before injection takes place, baseline surveys must be collected to understand the background and provide a basis for difference mapping.
3. **Operational monitoring:** During injection, injection wells are monitored to look for circulation behind casing, failures within the well bore, and other operational problems or failures.
4. **Array monitoring during and after injection:** This phase will involve active surface and subsurface arrays, with the potential for additional tools around high-risk zones. The recurrence and total duration of monitoring will be determined by the research goals, the site parameters, the commercial status and regulatory needs. Ideally, MMV data would be formally integrated to reduce operational cost and complexity and to provide higher fidelity.

The likely duration of monitoring is an important unresolved issue. It is impractical for monitoring to continue for hundreds of years after injection; a practical monitoring time period should be defined either generally or at each site before injection begins. Substantial uncertainties remain regarding the detection thresholds of various tools, since the detection limit often involves assumptions about the distribution, continuity, and phase of subsurface CO₂. Important issues remain about how to optimize or configure an array to be both effective and robust. This issue cannot be answered without testing and research at large-scale projects and without formal data integration.

Leakage Risks

Since CO₂ is buoyant in most geological settings, it will seek the earth's surface. Therefore, despite the fact that the crust is generally well configured to store CO₂, there is the possibility of leakage from storage sites.³ Leakage of CO₂ would negate some of the benefits of sequestration²⁴ If the leak is into a contained environment, CO₂ may accumulate in high enough concentrations to cause adverse health, safety, and environmental consequences.^{25,26,27} For any subsurface injected fluid, there is also the concern for the safety of drinking water.²⁸ Based on analogous experience in CO₂ injection such as acid gas disposal and EOR, these risks appear small. However, the state of science today cannot provide quantitative estimates of their likelihood.

Importantly, CO₂ leakage risk is not uniform and it is believed that most CO₂ storage sites will work as planned.²⁹ However, a small percentage of sites might have significant leakage rates, which may require substantial mitigation efforts or even abandonment. It is important to note that the occurrence of such sites does not negate the value of the effective sites. However, a premium must be paid in the form of due diligence in assessment to quantify and circumscribe these risks well.

Wells almost certainly present the greatest risk to leakage,³⁰ because they are drilled to bring large volumes of fluid quickly to the earth's surface. In addition, they remove the aspects of the rock volume that prevent buoyant migration. Well casing and cements are susceptible to corrosion from carbonic acid. When wells are adequately plugged and completed, they trap CO₂ at depth effectively. However, there are large numbers of orphaned or abandoned wells that may not be adequately plugged, completed, or cemented (Appendix 4.2) and such wells represent potential leak points for CO₂. Little is known about the specific probability of escape from a given well, the likelihood of such a well existing within a potential site, or the risk such a well presents in terms of potential leakage volume or consequence.^{30,31} While analog situations provide some quantitative estimates (e.g, Crystal Geyser, UT)³², much remains to be done to address these questions. Once a well is identified, it can be plugged or recompleted at fairly low cost.

There is the possibility of difficult to forecast events of greater potential damage. While these events are not analogous for CO₂ sequestration, events like the degassing of

volcanic CO₂ from Lake Nyos³³ or the natural gas storage failure near Hutchinson, Kansas³⁴ speak to the difficulty of predicting unlikely events. However, while plausible, the likelihood of leaks from CO₂ sequestration causing such damage is exceedingly small (i.e., the rate of any leakage will be many orders of magnitude less than Lake Nyos and CO₂ is not explosive like natural gas).

Even though most potential leaks will have no impact on health, safety, or the local environment, any leak will negate some of the benefits of sequestration. However, absolute containment is not necessary for effective mitigation.^{Error! Bookmark not defined.} If the rate and volume of leakage are sufficiently low, the site will still meet its primary goal of sequestering CO₂ to reduce atmospheric warming and ocean acidification. The leak would need to be counted as an emissions source as discussed further under liability. Small leakage risks should not present a barrier to deployment or reason to postpone an accelerated field-based RD&D program.³⁵ This is particularly true of early projects, which will also provide substantial benefits of learning by doing and will provide insight into management and remediation of minor leaks.

A proper risk assessment would focus on several key elements, including both likelihood and potential impact. Efforts to quantify risks should focus on scenarios with the greatest potential economic or health and safety consequences. An aggressive risk assessment research program would help financiers, regulators, and policy makers decide how to account accurately for leakage risk.

Science & technology gaps

A research program is needed to address the most important science and technology gaps related to storage. The program should address three key concerns: (1) tools to simulate the injection and fate of CO₂; (2) approaches to predict and quantify the geomechanical response to injection; and (3) the ability to generate robust, empirically based probability-density functions to accurately quantify risks.

Currently, there are many codes, applications, and platforms to simulate CO₂ injection.³⁶ However, these codes have substantial limitations. First, they do not predict well the geomechanical response of injection, including fracture dilation, fault reactivation, cap-rock integrity, or reservoir dilation. Second, many codes that handle

reactive transport³⁷ do not adequately predict the location of precipitation or dissolution, nor the effects on permeability. Third, the codes lack good modules to handle wells, specifically including the structure, reactivity, or geomechanical response of wells. Fourth, the codes do not predict the risk of induced seismicity. In order to simulate key coupled processes, future simulators will require sizeable computational resources to render large complex sedimentary networks, and run from the injection reservoir to the surface with high resolution in three dimensions. Given the capability of existing industry and research codes, it is possible to advance coupling and computation capabilities and apply them to the resolution of outstanding questions.

There is also a need to improve geomechanical predictive capability. This is an area where many analog data sets may not provide much insight; the concerns focus on rapid injection of large volumes into moderate-low permeability rock, and specific pressure and rate variations may separate reservoirs that fail mechanically from those that do not. This is particularly true for large-volume, high-rate injections that have a higher chance of exceeding important process thresholds. Fault response to stress, prediction of induced seismicity, fault transmissivity and hydrology, and fracture formation and propagation are notoriously difficult geophysical problems due to the complex geometries and non-linear responses of many relevant geological systems. Even with an improved understanding, the models that render fracture networks and predict their geomechanical response today are fairly simple, and it is not clear that they can accurately simulate crustal response to injection. A program that focuses on theoretical, empirical, laboratory, and numerical approaches is vital and should take advantage of existing programs within the DOE, DOD, and NSF.

The objective of these research efforts is to improve risk-assessment capabilities that results in the construction of reliable probability-density functions (PDFs). Since the number of CO₂ injection cases that are well studied (including field efforts) are exceedingly small, there is neither theoretical nor empirical basis to calculate CO₂-risk PDFs. Accurate PDFs for formal risk assessment could inform decision makers and investors regarding the potential economic risks or operational liabilities of a particular sequestration project.

In terms of risk, leakage from wells remains the likeliest and largest potential risk.^{31,38} The key technical, regulatory, and legal concerns surrounding well-bore leakage of CO₂ are discussed in Appendix 4.3.

Need for studies at scale

Ultimately, for CCS to substantially reduce GHG emissions in the future, most facilities will comprise large-scale injections. Because the earth's crust is a complex, heterogeneous, non-linear system, field-based demonstrations are required to understand the likely range of crustal responses, including those that might allow CO₂ to escape from reservoirs. In the context of large-scale experiments, the three large volume projects currently operating do not address all relevant questions. Despite a substantial scientific effort, many parameters which would be measured to circumscribe the most compelling scientific questions have not yet been collected (see Table 4.1), including distribution of CO₂ saturation, stress changes, and well-bore leakage detection. This gap could be addressed by expanded scientific programs at large-scale sites, in particular at new sites.

The projects sponsored by the DOE are mostly small pilot projects with total injection volume between 1000 and 10,000 metric tons. For example, the DOE sponsored a field injection in South Liberty, TX, commonly referred to as the Frio Brine Pilot.^{39, 40} The Pilot received ~1800 t of CO₂ in 2004, and is slated to receive a second injection volume of comparable size in 2006. The Regional Partnerships have proposed 25 geological storage pilots of comparable size, which will inject CO₂ into a wide array of representative formations.¹⁶ These kinds of experiments provide value in validating some model predictions, gaining experience in monitoring, and building confidence in sequestration. However, pilots on this scale cannot be expected to address the central concerns regarding CO₂ storage because on this scale the injection transients are too small to reach key thresholds within the crust. As such, important non-linear responses that may depend on a certain pressure, pH, or volume displacement are not reached. However, they will be reached for large projects, and have been in each major test.

As an example, it has been known for many years that fluid injections into low-permeability systems can induce earthquakes small and large.⁴¹ It is also known that while injection of fluids into permeable systems can induce earthquakes, even with large

injection volumes the risk of large earthquakes is extremely low. The best example is a set of field tests conducted at Rangely oilfield in NW Colorado, where an aggressive water-injection program began in an attempt to initiate and control seismic events.⁴² Despite large injections, the greatest moment magnitude measured as M_L 3.1. Since that time, over 28 million tons of CO₂ have been injected into Rangely with limited seismicity, no large seismic events, and no demonstrable leakage (IEA doc; Klusman 2005).⁴³ These studies make clear that injections of much smaller volumes would produce no seismicity. Thus to ascertain the risk associated with large injections requires large injection, as do the processes and effects of reservoir heterogeneity on plume distribution or the response of fractures to pressure transients.

Large scale demonstrations as central short-term objective

Ultimately, large-scale injections will require large volumes of CO₂ to ensure that injection transients approach or exceed key geological thresholds. The definition of large-scale depends on the site since local parameters vary greatly. In highly permeable, continuous rock bodies (e.g., Frio Fm. or Utsira Fm.), at least one million tons/yr may be required to reach these thresholds; in low permeability (e.g., Weber Sandstone or Rose Run Fm.) or highly segmented reservoirs, only a few 100,000 tons/year may be required. A large project would likely involve multiple wells and substantial geological complexity and reservoir heterogeneity (like In Salah and Weyburn). To observe these effects would likely require at least 5 years of injection with longer durations preferred.

Because of the financial incentives of additional production, CO₂-EOR will continue to provide early opportunities to study large-scale injection (e.g., Weyburn). However, the overwhelming majority of storage capacity remains in saline formations, and there are many parts of the country and the world where EOR options are limited. Since saline formations will be central to substantial CO₂ emissions reduction, a technical program focused on understanding the key technical concerns of saline formations will be central to successful commercial deployment of CCS.

Costs for the large projects are substantial. For phase I, the Weyburn project spent \$27 million, but did not include the costs of CO₂ or well drilling in those costs. Because of cost constraints, the Weyburn project did not include important monitoring and

scientific studies. The cost of CO₂ supply could be low if one assumes that the CO₂ supply were already concentrated (e.g., a fertilizer or gas processing stream) and compression would be the largest operating cost. If CO₂ required market purchase (e.g., from KinderMorgan pipelines into the Permian Basin), then a price of \$20/ton CO₂ would represent a likely upper cost limit. Total cost would include compression costs, well count, reworking requirements, availability of key data sets, and monitoring complement. Based on these types of consideration, an eight-year project could achieve key technical and operational goals and deliver important new knowledge for a total cost between \$100 – 225 million, corresponding to an annual cost roughly between \$13 – 28 million. A full statement of the assumption set and calculation is presented in Appendix 4.2.

In sum, a well-instrumented sequestration project, at the necessary scale required to yield important information is large. However, only a small number of projects are likely to be required to deliver the needed insights for the most important set of geological injection conditions. For example, in the US only 3-4 sites might be needed to demonstrate and parameterize safe injection. These sites could include one project in the Gulf Coast, one in the central or northern Rocky Mountains, and one in either the Appalachian or Illinois basins (one could consider adding a fourth project in California, the Williston, or the Anadarko basins). This suite would cover an important range of population densities, geological and geophysical conditions, and industrial settings (Figure 4.4). More importantly, these 3-4 locations and their attendant plays are associated with large-scale current and planned coal-fired generation, making their parameterization, learning, and ultimate success important.

The value of information derived from these studies relative to their cost would be enormous. Using a middle cost estimate, all three basins could be studied for \$500 million over eight years. Five large tests could be planned and executed for less than \$1 billion, and address the chief concerns for roughly 70% of potential US capacity. Information from these projects would validate the commercial scalability of geological carbon storage and provide a basis for regulatory, legal, and financial decisions needed to ensure safe, reliable, economic sequestration.

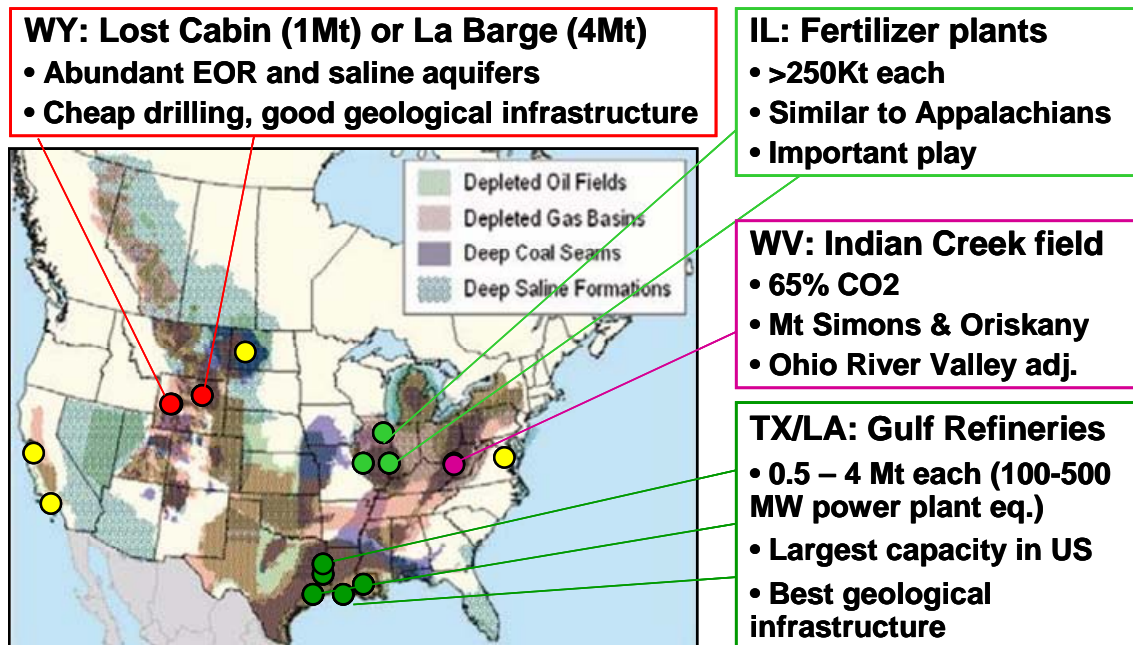


Figure 4.4. Draft suggestions for 4 large UC storage projects using anthropogenic CO₂ sources

The requirements for sequestration pilot studies elsewhere in the world are similar. The number of projects needed to cover the range of important geological conditions around the world to verify the storage capacity is of order 10. Using the screening and selection parameters described in Appendix 4.2, we believe that the world could be tested for approximately a few billion dollars. The case for OECD countries to help developing nations test their most important storage sites is strong – the mechanisms remain unresolved and are likely to vary case to case.

Developing Countries

Developing nations, particularly China and India, will grow rapidly in the coming decades with an even more rapid growth in energy demand. Both countries have enormous coal reserves, and have plans to greatly increase national electrification with coal power. Projections for CO₂ emissions in both countries grow as a consequence, with the possibility that China will become the world's largest CO₂ emitter by 2030. Therefore it is important to know what sequestration options exist for both nations.

China

The geological history of China is immensely complicated.^{44,45} This history has produced 28 onshore sedimentary basins with roughly 10 large offshore basins (Figure 4.5). This presents a substantial task in geological assessment. However, many of these basins (e.g., Tarim, Junggar basins) are not near large CO₂ point sources or population centers and do not represent an assessment priority. Six on shore and two offshore basins with relatively simple geological histories lie in the eastern half of China,⁴⁶ close to coal sources, industrial centers, and high population densities. These are also the basins containing the largest oil-fields and gas fields in China.⁴⁷ Preliminary assessment suggests that these basins have prospectivity.⁴⁸ The initial estimates are based on injectivity targets of 100 mD, and continued assessment will change the prospectivity of

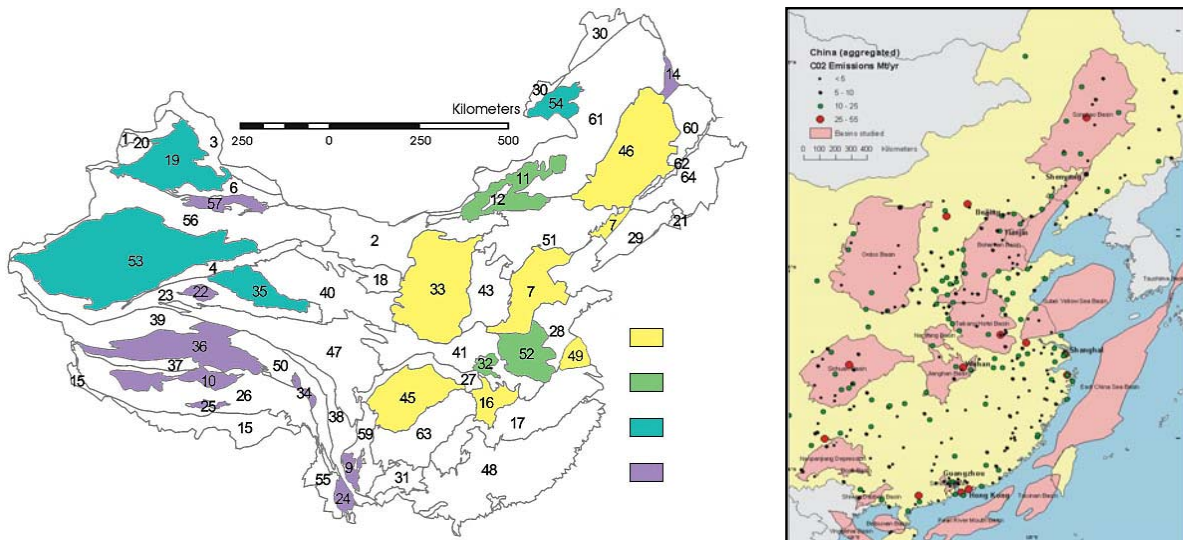


Figure 4.5. LEFT: Tectonic map of onshore China; all colored areas are sedimentary basins. Yellow represent high priority for assessments; green represent second tier; blue represent third tier; fourth tier are purple. Ranking is based on closeness to CO₂ point sources, presence of hydrocarbons, and complexity of geology. RIGHT: East China onshore and offshore basins with annual CO₂ emissions.⁴⁸ these basins.

There are a number of active sequestration projects in China. RIPED, CNPC, and other industrial and government entities are pursuing programs in CO₂-EOR. These are driven by economic and energy security concerns; continued study will reveal the potential for storage in these and other fields. Some western companies are also pursuing low-cost CO₂ projects; Shell is investigating a large CO₂ pilot, and Dow has announced plans to sequester CO₂ at one of its chemical plants. There is a 192 tonne Canadian-Chinese ECBM project in the Quinshui basin. However, there is much greater potential

for very large CO₂ storage tests using low-cost sources. China has many large coal gasification plants, largely for industrial purposes (e.g., fertilizer production, chemical plants). A number of these plants vent pure streams well in excess of 500,000 tons/y, and many are located within 150 km of viable geological storage and EOR targets.⁴⁹

A program to determine the viability of large-scale sequestration in China would be first anchored in a detailed bottom-up assessment. The data for assessments exists in research institutions (e.g., RIPED, the Institute of for Geology and Geophysics) and the long history of geological study and infrastructure^{50,51} suggests that Chinese teams could execute a successful assessment in a relatively short time, which could be followed by large injection tests. Given the central role of China's emissions and economy in the near future and the complexity of its geology, this should involve no less than two large projects. One might target a high-value, high chance of success opportunity (e.g., Bohainan basin; Songliao). Another might target lower permeability, more complicated targets (e.g., Sichuan or Jiangnan basin). In all cases, large projects do not need to wait for the development of IGCC plants, since there is already enormous gasification capacity and large pure CO₂ streams near viable targets. As with any large target, a ranking of prospects and detailed geological site characterization would be key to creating a high chance of project success.

India

Geologically, India is a large granitic and metamorphic massif surrounded by sedimentary basins. These basins vary in age, complexity, and size. The largest sedimentary basin in the world (the Ganga basin) and one of the largest sedimentary accumulations (the Bengal fan) in India are close to many large point sources. In addition, a large basaltic massif (the Deccan Traps) both represents a potential CO₂ sink and also overlies a potential CO₂ sink (the underlying basins).

Currently, there is one CO₂ storage pilot planned to inject a small CO₂ volume into basalts. There are currently no plans for a detailed assessment or large-scale injection program. However, the IEA has announced a program to conduct an assessment. Many governmental groups have relevant data, including the Directorate General for Hydrocarbons, the Geological Survey of India, and the National Geophysical Research Institute. Several companies appear well equipped to undertake such work, including the

Oil and Natural Gas Company of India. Despite the Indian government's involvement in the CSLF and FutureGen, it has not yet made the study of carbon sequestration opportunities a priority.

Current Regulatory Status

At present, there is no regulatory regime in place for geological sequestration of CO₂. At a minimum, the regulatory regime needs to cover the injection of CO₂, accounting and crediting as part of a climate regime, and site closure and monitoring. In the United States, there does exist regulations for underground injections (see discussion below), but there is no category specific to CO₂ sequestration. A regulatory capacity must be built, whether from the existing EPA underground injection program or from somewhere else. ***Building a regulatory framework for CCS should be considered a high priority item.*** The lack of a framework makes it more difficult and costly to initiate large-scale projects and will result in delaying large-scale deployment

In the United States, there is a body of federal and state law that governs underground injection to protect underground sources of drinking water. Under authority from the Safe Drinking Water Act, EPA created the Underground Injection Control (UIC) Program, requiring all underground injections to be authorized by permit or rule and prohibiting certain types of injection that may present an imminent and substantial danger to public health. Five classes of injection wells have been set forth in the regulations, none specific to geological sequestration. A state is allowed to assume primary responsibility ("primacy") for the implementation and enforcement of its underground injection control program if the state program meets the requirements of EPA's UIC regulations. As shown in Figure 7, thirty-three states have full primacy over underground injection in their state, seven states share responsibility with EPA, and ten states have no primacy. A state program may go beyond the minimum EPA standards; in Nevada, for example, injection is not allowed into any underground aquifer regardless of salinity, which negates a potential sequestration option (Nevada Bureau of Mines and Geology, 2005).

The UIC achieves its primary objective of preventing movement of contaminants into potential sources of drinking water due to injection activities, by monitoring

contaminant concentration in underground sources of drinking water. If traces of contaminants are detected, the injection operation must be altered to prevent further pollution.

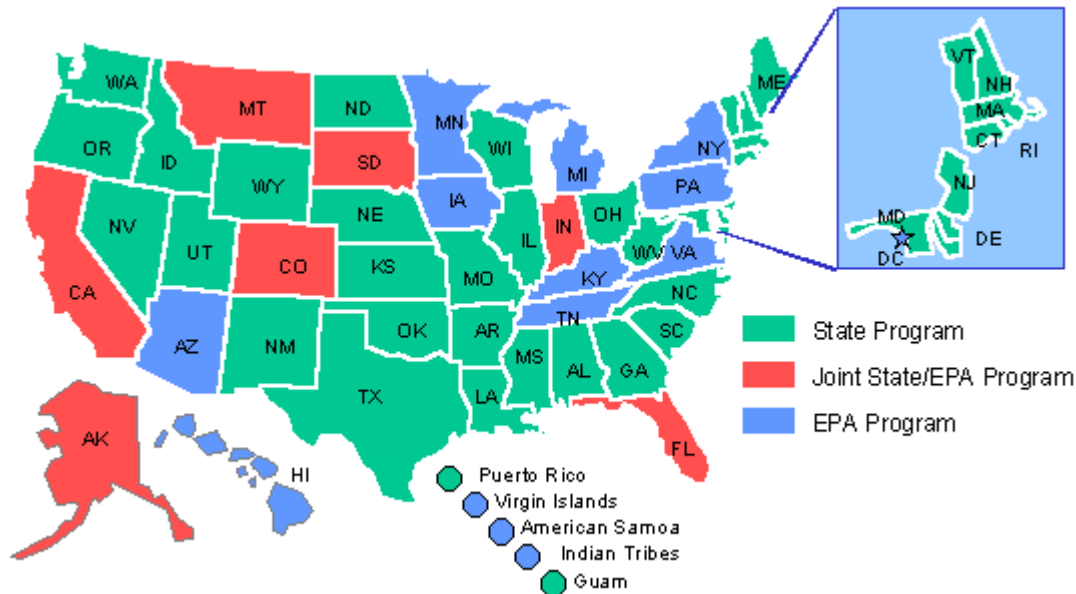


Figure 4.6: Current state and EPA underground injection control programs (Source: EPA)

There are no federal requirements under the UIC Program to track the migration of injected fluids within the injection zone or to the surface.⁵² Lack of fluid migration monitoring is problematic when the UIC regulatory regime is applied to geological sequestration. For example, one source of risk for carbon sequestration is that injected CO₂ potentially leaks to the surface through old oil and gas wells. For various reasons, such as existing infrastructure and proved cap rock, the first geological sequestration projects in the US will likely take place at depleted oil and gas fields. These sites possess numerous wells, some of which can act as high permeability conduits to the surface. Plugs in these wells may be lacking, poor, or subject to corrosion from CO₂ dissolved in brine. The presence of wells at sequestration sites greatly increases the chance for escape of injected gas. Regulations will be needed for the particular circumstance of CO₂ storage. This will involve either modification of the UIC regulations or creation of a new framework.

Unlike onshore geological sequestration, which is governed by national law, offshore geological sequestration is governed by international law. Offshore sequestration has not been specifically addressed in any multilateral environmental

agreements that are currently in force, but may fall under the jurisdiction of international and regional marine agreements, such as the 1972 London Convention, the 1996 Protocol to the London Convention, and the 1992 OSPAR Convention. Because these agreements were not designed with geological sequestration in mind, they may require interpretation, clarification, or amendment by their members. Most legal scholars agree that there are methods of offshore sequestration currently compatible with international law, including using a land-based pipeline transporting CO₂ to the sub-seabed injection point and injecting CO₂ in conjunction with offshore hydrocarbon activities.⁵³

Liability

Liability of CO₂ capture and geological sequestration can be classified into operational liability and post-injection liability.

Operational liability, which includes the environmental, health, and safety risks associated with carbon dioxide capture, transport, and injection, can be managed within the framework that has been successfully managed for decades by the oil and gas industries.

Post-injection liability, or the liability related to sequestered carbon dioxide after it has been injected into a geologic formation, presents unique challenges due to the expected scale and timeframe for sequestration. The most likely sources of post-injection liability are groundwater contamination due to subsurface migration of carbon dioxide, emissions of carbon dioxide from the storage reservoir to the atmosphere (i.e., non-performance), risks to human health, damage to the environment, and contamination of mineral reserves. Our understanding of these risks needs to be improved in order to better assess the liability exposure of operators engaging in sequestration activities.

In addition, a regulatory and liability framework needs to be adopted for the closing of geological sequestration injection sites. The first component of this framework is monitoring and verification. Sequestration operations should be conducted in conjunction with modeling tools for the post-injection flow of carbon dioxide. If monitoring validates the model, a limited monitoring and verification period (5-10 years) after injection operations may be all that is required, with additional monitoring and verification for exceptional cases. The second component of the framework defines the

roles and financial responsibilities of industry and government after abandonment. A combination of a funded insurance mechanism with government back-stop for very long-term or catastrophic liability will be required. Financial mechanisms need to be considered to cover this responsibility. There are a number of ways in which the framework could proceed. For example, in the case of nuclear power, the Price-Anderson Act requires that nuclear power plant licensees purchase the maximum amount of commercial liability insurance available on the private market and participate in a joint-insurance pool. Licensees are not financially responsible for the cost of any accident exceeding these two layers of insurance. Another example would be the creation of a fund with mandatory contributions by injection operators. We suggest that industry take financial responsibility for liability in the near-term, i.e. through injection phase and perhaps 10-20 years into the post-injection phase. Once certain validation criteria are met, government would then assume financial responsibility, funded by industry insurance mechanisms, and perhaps funded by set-asides of carbon credits equal to a percentage of the amount of CO₂ stored in the geological formation.

Sequestration Costs

Figure 4.7 shows a map of US coal plants overlayed with potential sequestration reservoirs. The majority of coal-fired power plants are situated in regions where there are high expectations of having CO₂ sequestration sites nearby. In these cases, the cost of transport and injection of CO₂ should be less than 20% of total cost for capture, compression, transport, and injection.

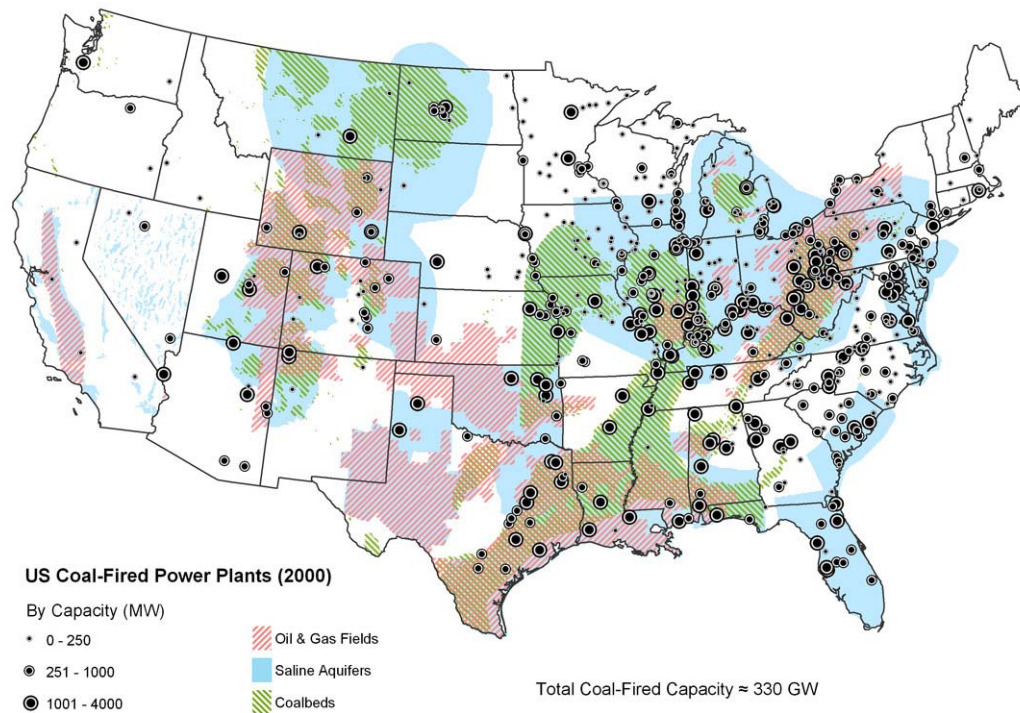


Figure 4.7. Map comparing location of existing coal-fired power plants in the US with potential sequestration sites. As stated earlier in the report, our knowledge of capacity for sequestration sites is very limited. Some shaded areas above may prove inappropriate, while detailed surveys may show sequestration potential in places that are currently not identified.

Transportation for commercial projects will be via pipeline, with cost being a function of the distance and quantity transported. As shown in Figure 4.8, transport costs are highly non-linear for the amount transported, with economies of scale being realized at about 10 Mt CO₂/yr. While Figure 4.8 shows typical values, costs can be highly variable from project to project due to both physical (e.g., terrain pipeline must traverse) and political considerations. For a 1 GW_e coal-fired power plant, a pipeline must carry about 6.2 Gt CO₂/yr (see footnote 1). This would result in a pipe diameter of about 16 inches and a transport cost of about \$1/tCO₂/100 km. Transport costs can be lowered through the development of pipeline networks as opposed to dedicated pipes between a given source and sink.

Costs for injecting the CO₂ into geologic formations will vary on the formation type and its properties. For example, costs increase as reservoir depth increases and reservoir injectivity decreases (lower injectivity results in the drilling of more wells for a given rate of CO₂ injection). A range of injection costs has been reported as \$0.5-8/tCO₂.³

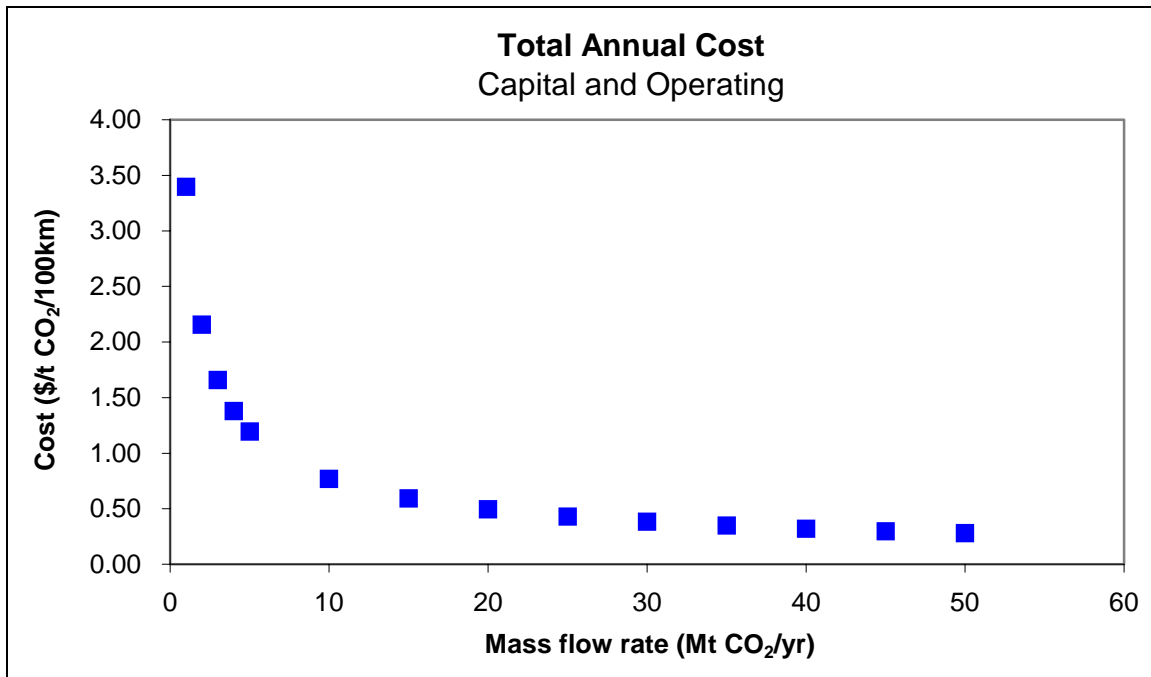


Figure 4.8: Cost for CO₂ transport via pipeline as a function of CO₂ mass flow rate

It is anticipated that the first CCS projects will involve plants that are very close to a sequestration site or an existing CO₂ pipeline. As the number of projects grow, regional pipeline networks will evolve. This is similar to the growth of existing regional CO₂ pipeline networks in west Texas and in Wyoming to deliver CO₂ to the oil fields for EOR. For example, Figure 4.7 suggests that a regional pipeline network may develop around the Ohio River valley.

Recommendations

Our overall judgment is that the prospect for geological CO₂ sequestration is excellent. We base this judgment on 30 years of injection experience and the ability of the earth's crust to trap CO₂. That said, there remain substantial open issues about large-scale deployment of carbon sequestration. Our recommendations aim to address the largest and most important of these issues. Our recommendations call for action by the U.S.

government; however, many of these recommendations are appropriate for OECD and developing nations who anticipate the use CCS.

1. The US Geological Survey and the DOE, and should embark of a 3 year “bottom-up” analysis of US geological storage capacity assessments. This effort might be modeled after the GEODISC effort in Australia.
2. The DOE should launch a program to develop and deploy large-scale sequestration demonstration projects. The program should consist of a minimum of three projects that would represent the range of US geology and industrial emissions with the following characteristics:
 - Injection of the order of 1 million tons CO₂/year for a minimum of 5 years.
 - Intensive site characterization with forward simulation, and baseline monitoring
 - Monitoring MMV arrays to measure the full complement of relevant parameters. The data from this monitoring should be fully integrated and analyzed.
3. The DOE should accelerate its research program for CCS S&T. The program should begin by developing simulation platforms capable of rendering coupled models for hydrodynamic, geological, geochemical, and geomechanical processes. The geomechanical response to CO₂ injection and determination or risk probability-density functions should also be addressed.
4. A regulatory capacity covering the injection of CO₂, accounting and crediting as part of a climate regime, and site closure and monitoring needs to be built. Two possible paths should be considered – evolution from the existing EPA UIC program or a separate program that covers all the regulatory aspects of CO₂ sequestration.
5. The government needs to assume liability for the sequestered CO₂ once injection operations cease and the site is closed. The transfer of liability would be contingent on the site meeting a set of regulatory criteria (see recommendation 4 above) and the operators paying into an insurance pool to cover potential damages from any future CO₂ leakage.

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